STATE OF MAINE
PUBLIC UTILITIES COMMISSION

October 14, 1994

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CENTRAL MAINE POWER COMPANY
Proposed Increase in Rates, Phase II

STIPULATION

Docket No. 92-345

This proceeding is intended to consider and resolve whether an Alternative Rate Plan, ("ARP" or "Plan"), should be adopted for Central Maine Power Company, ("CMP" or "Company"), and, if such a Plan is desirable, the terms and conditions of the Plan. This Stipulation evidences agreement among the signing parties that an ARP as set forth in this Stipulation is reasonable and should be adopted by the Commission.

The Plan contained in this Stipulation includes the following major features:

	PARAGRAPH	Attachment
Purpose	1-2	
Construction of Stipulation	3	
Effective Date of ARP	4	
Price Cap Mechanism	5	
Price Index	6	
Productivity Offset And QF Factor	6	
Profit Sharing Mechanism	7	A & B
QF Contract Restructuring and Sharing Component	8-10	C & D
Flowthroughs and Mandated Costs	11-12	E
Operation of Electric Lifeline Program	13	
Restructuring Charges	14	
Pricing Flexibility	15	F
Customer Service Standards	16	G
Least Cost Planning and Demand-side Management Incentives	17	H
Option to Review Rates	18	
Prudency Reviews	19	
Annual Reporting	20	I
Mid-Period Review	21	
Accounting Conventions	22	J
Final Review	23	
Procedural Matters	24-25	

The undersigned, being parties to this proceeding, agree as follows:

1. Purpose. It is the purpose of this Stipulation to resolve all issues in this docket, except, as otherwise specified herein, for the purpose of avoiding unnecessary litigation and expense and to jointly offer the Commission a single comprehensive Alternative Rate Plan consistent with the objectives and guidance set forth by the Commission in its Order in Phase I of this proceeding.

2. The parties to this Stipulation support a change in the form of rate regulation to the ARP as set forth in this Stipulation for reasons that include potential benefits such as producing a higher degree of price stability and predictability, reducing regulatory costs, creating stronger incentives for cost minimization, shifts risks away from ratepayers, while retaining comprehensive regulation of rates and energy policy compliance and providing a form of regulation that will allow CMP needed flexibility to compete in a changing electric utility business environment.

3. Construction of Stipulation. This proceeding involves a number of parties each having brought to the proceeding a specific list of issues and areas of concern for resolution. This Stipulation reflects a delicate balance among a variety of competing interests and objectives; changing any one provision could upset the balance achieved by all parties. Therefore, the parties explicitly agree that this Stipulation be considered by the Commission for its adoption as an integrated solution to the issues in these proceedings and shall be null and void and shall not bind the parties in this proceeding if the Commission does not accept this Stipulation without modification.

4. Effective Date of the ARP. The ARP shall take effect upon approval by the Commission and it is the intent of the parties that the ARP become effective on or before December 1, 1994. Thus, the Company may file pricing flexibility changes immediately upon the effective date. The first price cap change will be implemented on July 1, 1995.

5. Pricing Cap Mechanism. Each July 1, beginning on July 1, 1995, the cap on each of CMP's rates for retail electric service will change by a percentage equal to the total of the following four items: (1) inflation index, (2) less productivity offset and QF factor, plus or minus, (3) sharing mechanism, and plus or minus, (4) flowthrough items and mandated costs. The index shall be a single index applied to all CMP's rates and no separate index, tracking mechanism, or pre-set fuel price change mechanism or schedule shall be applied. Other than changes in rates pursuant to the operation of the price cap mechanism, Central Maine Power Company's rates, both base and fuel, will not change during the period of the ARP from any filing for base rates under 35-A M.R.S.A. §307, or 35-A M.R.S.A. §1322, or for fuel rates under 35-A M.R.S.A. §3101. Further, upon the expiration of the term of the ARP on December 31, 1999 (whether subsequently extended or not by the Commission) Central Maine will not be entitled to recover under 35-A M.R.S.A. §3101 uncollected fuel costs, if any.

6. Price Index

a. Inflation Index - The index used for measuring inflation will be the Gross Domestic Product - Price Index ("GDP-PI") for the prior calendar year as specified in Attachment I.

b. Productivity Offset and QF Factor
The inflation index will be reduced to reflect general productivity ("productivity offset") and

the fact that the costs of a substantial amount of the Company's purchased power contracts with qualifying facilities are not subject to inflation-driven increases ("QF factor"). The formula, which will be phased in and fully effective by 1997, reflects a general productivity offset of 1.0% and a QF factor of .375, based on an assumption that 37.5% of CMP's total costs are not inflation driven. The price index formula, in each year of the ARP, is as follows:

1995: Price index=inflation factor - .5%

1996: For inflation <=4.5%, Price index=(inflation-1.0%)

For inflation>4.5%, Price index equals the greater of

a) 3.5% or

b) (1-.375)x(inflation-1.0%)

1997-1999: (1-.375)x(inflation-1.0%)

An illustration of the price index for 1997-99 under various rates of inflation is set forth below:

Inflation	Productivity Offset and QF Factor	Price Index
3%	1.75%	1.25%
4%	2.125%	1.875%
5%	2.50%	2.50%
6%	2.875%	3.125%

7. Profit-Sharing Mechanism. A profit-sharing mechanism, rather than the triggering of a rate review, will be used to adjust the subsequent year's price change in the event that earnings are outside a specified deadband. The profit-sharing mechanism will not be in effect for the price change to take

place on July 1, 1995, but will be in effect for each price change taking place on or after July 1, 1996. This mechanism will operate as follows:

a. The deadband will range from three hundred fifty (350) basis points below the allowed return on equity as computed pursuant to this Paragraph to three hundred fifty (350) basis points above the return on equity computed under this Paragraph.

b. The return on equity, which will be the starting point for determination of whether the profit-sharing mechanism is triggered, will be computed on a "financial reporting basis" adjusted as required by law or regulation to exclude revenues, expenses and profits/losses that must be removed for rate recovery. This methodology is set forth in Attachment A.

c. Outside the dead-band, profits and losses will be shared on a fifty-fifty basis between customers and shareholders. This will be accomplished by a price cap decrease equal to 50% of any excess revenues over the upper end of the bandwidth or a price cap increase equal to 50% of the revenue deficiency below the lower end of the bandwidth. Earnings will be computed on a calendar year basis and the profit sharing, if any, will be implemented in the price change effective on July 1 of the year immediately succeeding the year when earnings fell outside the deadband.

d. The target return on equity will be indexed for purposes of the profit sharing mechanism beginning with the price change effective on July 1, 1996. The details of the indexing mechanism are set forth in Attachment B.

8. <u>Sharing Mechanism for Restructurings of Purchased Power Agreements With Qualifying Facilities</u>. Except as set forth in paragraphs 9 and 10 the Company will flowthrough to ratepayers fifty percent, (50%), of annual net savings or net costs derived

from all contract restructurings consummated after October 1, 1994, of any purchased power agreements with qualifying facilities. The remaining portion (50%) of net savings or net costs will accrue to shareholders and will be recognized in the computation of earnings for calculation of profit sharing as set forth in paragraph 7. The computation of net savings or net costs is described in Attachment C.

9. Flowthrough of Savings From Buyout of Fairfield Energy Venture. There will be a rate reduction of one million four hundred thousand ($1,400,000) from the buyout of the Fairfield Energy Venture that will take place as a mandated cost decrease on July 1, 1995. This rate reduction together with the $5.6 million rate reduction associated with the FEV buyout, that is currently scheduled to become effective December 1, 1994 and is set forth in the October 5, 1994 Supplemental Order in Docket No. 94-103, will be in lieu of the $3 million estimated mandated rate decrease scheduled to be effective in 1997, as set forth in paragraph 7 of the Stipulation approved by the Commission on August 18, 1994 in Docket No. 94-213. In addition any savings from the Fairfield buyout that exceed the rate reductions flowed through to customers through the December 1, 1994 and July 1, 1995 rate reductions or additional costs that have been or will be incurred associated with the operation of the Fairfield Facility will be flowed through as a mandated cost adjustment as described in Attachment D.

10. Flowthrough of All Net Savings From Restructuring of Purchased Power Agreements with Qualifying Facilities Financed Through the Finance Authority of Maine. Pursuant to P.L. 1994 Ch. 712. All net savings or net costs derived from restructuring of purchased power agreements with qualifying facilities, which are financed through FAME, pursuant to P.L. 1994 Ch. 712, will, in proportion to the amount financed with FAME funds, be flowed

through to customers on an annual basis as a mandated cost. The mechanism for achieving this result is described in Attachment D.

11. Cost Recovery for Demand-side Management and FAS 106 Costs. Increases and decreases in these costs will be flowed directly through to customers as part of each annual review. Specific recovery will be provided for:

a. All costs of demand-side management which receive either deferred or reconcilable treatment will be recovered as a flowthrough item. Beginning with the July 1996 increase,the revenue requirements associated with prior year deferred demand-side management spending will be included in the price change. No change will occur in the rate treatment of reconcilable demand-side management except that the price increase for these costs will be limited to $2 million in any given year, with no increase in 1995. Expenditures in excess of amounts in rates will be deferred for future recovery. This provision is not intended to, in any way, effect the level of the Company's DSM expenditures or its right to full recovery of all costs prudently incurred.

b. The costs of transition to FAS No. 106 ("Accounting for Post-retirement Benefits Other Than Pensions"). CMP has agreed that 50% of the difference between the full FAS No. 106 accrual cost and the pay-as-you-go costs will be recovered through an additional revenue adjustment above the index and that this amount will be phased in ratably over three years beginning with the price change to be implemented on July 1, 1995. This methodology is demonstrated in Attachment E.

12. Definition and Scope of Mandated Costs and Z-factors. Because of their nature, the parties agree that certain costs must be kept separate from the index-based price cap change and

that the number of these costs be kept to a minimum. The parties recognize there may be extraordinary costs imposed on CMP, which could have an impact on its costs that are not covered by the index. Lacking an adjustment to the price index mechanism CMP would experience a windfall gain if its costs fell, or a windfall loss if its costs rose. To qualify for direct rate treatment, such costs must be approved by the Commission. In order for these costs to be considered by the Commission for recovery as mandated costs, such costs must exceed three million dollars, ($3,000,000), in annual revenue requirements at the time of inclusion in rates for each item and should at least have a disproportionate effect on CMP or the electric power industry and would not adequately be accounted for through the index. Certain tax changes, regulatory changes, accounting changes, and natural disasters are candidates for mandated cost treatment. Increases or decreases in these costs, when applicable, will be treated as part of each annual review and price change. Mandated costs that are non-recurring in nature will be removed from rates in the year following full recovery of the cost item.

13. Operation of Electric Lifeline Program. ELP benefits will be funded at current levels. The parties, pursuant to the Order in Docket No. 94-185, will continue to seek consensus on one or more acceptable methodologies for curtailment of ELP spending under the scenarios set forth in the August 22 Order. Any differences between the amount funded through current rates and actual benefit expense will be deferred until the 1997 mid-period review.

14. Restructuring Charges. In order to mitigate price pressures, reduce ratepayer risks and better position the Company to achieve timely restoration of competitive financial results, CMP will take the following restructuring charges against 1994 earnings:

a. The balance of Deferred Fuel as of December 31, 1994, in excess of the balance related to current month billing lags, will be eliminated in its entirety. This amount is estimated to be approximately $57 million. Thus, carrying costs of approximately $2.3 million annually will cease contributing to the mitigation of price increases. In the event the ARP is terminated before the end of the anticipated five year period, no amounts related to this balance would be recovered from customers.

b. Expenditures for Deferred Demand-side Management in 1993 and 1994 will be eliminated. This amount is anticipated to be approximately $17 million. In addition to contributing to mitigating 1995's price increase, the write-off of this item will cease the accrual of carrying costs of approximately $.7 million on an annual basis.

c. The balance in Accrued Utility Revenues -ERAM as of December 31, 1994 will be eliminated. This amount is estimated to be approximately $24 million.

d. The balance of deferred costs related to Wyman Station Life Extension as of December 31, 1994 will be eliminated. This amount will be approximately $2.5 million.

15. <u>Pricing Flexibility</u>. The Company may change its prices in accordance with the terms and conditions for pricing flexibility as set forth in Attachment F. The parties agree to use their best efforts to recommend for Commission approval "interim floor prices" to be used for the purpose of pricing flexibility during the period December 1, 1994 through the establishment of floor prices in accordance with the provisions setforth in Attachment F. The parties intent that the issue of "interim floor prices" be resolved by January 1, 1995. If unresolved, the Company will have the right to petition the Commission for a decision on this issue.

To the extent that a rate change or contract is presented to the

Commission subsequent to December 1, 1994 and the parties have been unable to agree to the "interim floor prices" as of the date of the filing of any such rate or contract by the Company, then the Company will include in its filing the recommended "interim floor price" for such rate or contract and the Commission shall review and approve, deny or modify such "interim floor price" within thirty days of the filing date.

16. Customer Service. To assure the continuation of adequate service, explicit customer service penalties are provided to address customer satisfaction, service reliability and customer service. The details of this mechanism are set forth in Attachment G.

17. Least cost Planning and Demand-side Management. In order to ensure that the Company engages in least cost planning and demand-side management, consistent with State energy policy, the Company will file annual savings targets for the Company's DSM measures consistent with its Least Cost Energy Resource Plan to be filed on April 1, 1995, which will be updated annually and be subject to approval by the Commission. Upon final approval, these annual savings targets will serve as the basis for evaluating demand-side management performance and, if these targets are not achieved, certain penalty provisions will be triggered. The details of the filing requirements and operation of the penalty mechanism are set forth in Attachment H. For use in implementing the performance targets and penalty mechanism for 1995 (deemed an interim period since the first Energy Resource Plan establishing DSM performance targets will not be filed until April 1995), Attachment H also includes a list of 1995 DSM commitments. These commitments are for the limited purpose of implementing the performance targets and penalty mechanism for DSM performance in 1995, but do not otherwise reflect agreement by the parties as to Company's fulfillment of

Least Cost Planning requirements.

18. Option to Review Rates and Least Cost Planning. In order to ensure that neither the Company nor the customers will be unduly harmed as a result of the ARP the Company will have an option to petition the Commission for a review of rates, revenue requirements and the overall ARP if the Company's actual return on equity falls outside of the sharing mechanism deadband for two consecutive years. The Company will not otherwise file for a general increase in rates. This paragraph in no way restricts the rights of other parties to petition the Commission for a review of rates. As set forth in Attachment H, in the event that the Company fails to achieve 90% of the demand-side management targets adopted in the Energy Resource Plan for two consecutive years, any party may petition for a Commission revision or termination of the ARP.

19. Prudency Reviews. The Stipulation is not meant to prevent the Commission from reviewing the prudency of the Company's operations and does not preclude any such review either on the Commission's own motion or upon request of another party. Any cost disallowance or other penalties would only be assessed against the Company in a situation where the profit-sharing mechanism was triggered. Cost disallowances, if any, associated with a Commission prudency review may not be included in the calculation of return of equity for purposes of the profit sharing mechanism as setforth in the computation of earnings in Attachment A.

20. Annual Reporting. CMP will file specified information each year on March 15. The information will be used to compute the annual price changes and to ensure compliance with all aspects of the ARP. Information will include:

(a) price index

(b) earnings sharing, if any

(c) flow through items, including net savings associated with QF contract restructuring sharing mechanism.

(d) pricing flexibility

(e) limited review of updated estimates of marginal cost

(f) review of customer service and reliability performance criteria

(g) review of compliance with demand-side management targets

(h) review of CMP's overall compliance with the provisions of the ARP

The details of the annual review process are more fully set forth in Attachment I. The Commission may modify the reporting requirements from time to time.

21. Mid Period Review. There will be a mid period review in 1997, to assess the overall operation and results of the ARP's performance. This review will explicitly consider the following:

a) Cost of Capital. The Commission shall consider and make explicit findings that determine CMP's cost of capital and appropriate capital structure. The Commission may also make changes to the ROE indexing mechanism.

b) Pricing Flexibility. The Commission shall consider the parameters of the pricing flexibility plan and may make any changes it finds reasonable and appropriate. This shall be a de novo review. The Commission shall make explicit findings relating to permanent load building and the need for the tests associated with permanent load as are currently set forth in the pricing flexibility component of this agreement.

c) ELP Funding. The Commission shall consider the recovery of any deferred ELP costs existing at the time of the mid period review consistent with paragraph 14 of this Stipulation.

d) Other ARP Components. The Commission may consider all other components of the ARP. This review could result in the modification or termination of the ARP. Except for the item discussed in subsections (a) (b) (c) of this paragraph, the components of the Plan as agreed to in this Stipulation will have the presumption of correctness and any party seeking to modify components of the Plan will have the burden of demonstrating that the modification is reasonable and appropriate.

Any person may seek to intervene in this the mid period review.

22. Accounting Conventions

The Alternative Rate Plan is not deregulation either from a ratemaking or an accounting perspective. Rather it is a change in the method employed to regulate price and cost of service recovery. The Company will continue to be subject to Generally Accepted Accounting Principles because the rates under the Alternative Rate Plan are intended to and meet the criteria of Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation." In particular, the accounting standards which specifically apply to regulated industries were considered in designing the Alternative Rate Plan and are an integral part of the Alternative Rate Plan. Those specific standards are discussed in Attachment J.

23. Final Review. In 1999, there will be an investigation to determine whether the ARP should continue after the end of

1999 and what changes to the ARP may be reasonable and appropriate for subsequent periods. If it is determined that an ARP should not continue, the Commission will determine the proper termination mechanisms consistent with the provisions of Section IV, item C of Attachment F. Any interested person may seek to intervene in the Final Review.

24. All Attachments referred to in this Stipulation are incorporated herein by reference and are intended to be considered as a part of this Stipulation as if their terms were fully set forth in the body of this Stipulation.

25. The making of this Stipulation by the Parties shall not constitute precedent as to any matter of law or fact, nor, except as expressly provided otherwise herein, shall it prevent any party from making any contention or exercising any right, including rights of appeal, in any other Commission proceeding or investigation or any other trial or action.

IN WITNESS WHEREOF, the Parties have caused this Stipulation to be executed by their respective attorneys or representatives, or have caused their lack of objection to be noted by the signature of their respective attorneys or representatives.

CENTRAL MAINE POWER COMPANY

October 14, 1994 BY: ______________________

PUBLIC UTILITIES COMMISSION STAFF

October ___, 1994 BY: ______________________

OFFICE OF THE PUBLIC ADVOCATE

October ___, 1994 BY:______________________________

COMMERCIAL CUSTOMER UTILITY COALITION

October ___, 1994 BY:______________________________

DEPARTMENT OF THE NAVY

October ___, 1994 BY:______________________________

AMERICAN ASSOCIATION OF RETIRED PERSONS

October ___, 1994 BY:______________________________

INDUSTRIAL ENERGY CONSUMER GROUP

October ___, 1994 BY:______________________________

BATH IRON WORKS CORPORATION

October ___, 1994 BY:______________________________

ALLIANCE TO BENEFIT CONSUMERS

October ___, 1994 BY:______________________________

Attachment A

Computation of Return on Equity Calculation Example for Profit Sharing Mechanism
(Dollars in Thousands)

BASED ON 1993 RESULTS FOR ILLUSTRATIVE PURPOSES ONLY

Electric Operating Revenue *		$887,038
Less Total Operating Expenses *	$787,556	
Plus Equity Earnings *	5,911	
Plus Total Other Income *	3,990	
Less Total Interest Charges *	48,081	
Less Dividends on Preferred Stock *	8,842	
Earnings Applicable to Common Stock		$52,460
Plus: Miscellaneous Income Deductions After Taxes (See Page 2)		$605
Items Specifically Disallowed by Comission After Taxes		2,327
Adjusted Earnings Applicable to Common Stock		$55,392
Average Common Stock Investment :		
Beginning Year *	$520,368	
Ending Year *	553,389	$536,879
Calculated Return on Common Equity		10.32%
Reported Return on Common Equity *		9.77%

* Source is CMP Monthly Financial Statements (unconsolidated)

Attachment A

Computation of Return on Equity Calculation Example
for Profit Sharing Mechanism
(Dollars in Thousands)

BASED ON 1993 RESULTS FOR ILLUSTRATIVE PURPOSES ONLY

Miscellaneous Income Deductions*:

FERC Accounts:

426.1	Donations		$320
426.2	Life Insurance		48
426.4	Expenditures for Certain Civic, Political and Related Activities		468
426.5	Other Deductions:		
	US Energy Assoc Utility Part.	$107	
	Community Activities	6	
	Institutional Advertising	65	178
426.3	Penalties		2

Miscellaneous Income Deductions Before Taxes		$1,016
Less Income Taxes at	40.4845%	411
Miscellaneous Income Deductions Before Taxes		$605

* Constitutes expenses not allowed by statute or rule to be recovered from ratepayers.

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Attachment B

<u>Indexing Mechanism for Return on Equity</u>

The return on equity to be used for earnings sharing purposes will be indexed by averaging, on a 12-month calendar year basis, the dividend yields on Moody's group of 24 electric utilities and Moody's utility bond yields. This index value will be compared to the base year average, (computed for the period July 1, 1992, through June 30, 1993), and the difference will be added to or subtracted from the current 10.55% authorized ROE.

(1) The ROE starting point for computing the profit sharing cannot increase or decrease by more than 200 basis points from the current 10.55%.

(2) Solely for purposes of the profit sharing mechanism, CMP's common equity ratio is limited to fifty percent (50%) until completion of the 1997 cost of capital review. At that time, any party may propose a modification to the 50% cap for the remaining portion of the ARP time period.

(3) To ensure effective operation of this indexing mechanism and to properly compensate CMP for its cost of capital, there will be a 1997 review of equity costs. The 200 basis point limitation will not limit changes in the revised allowable rate of return on common equity that will be approved by the Commission in the 1997 review. The 200 basis limitation will apply to subsequent index changes to the allowed rate of return on equity that is established in the 1997 review resulting from this review.

ATTACHMENT C
Contract Restructuring
<u>Measurement of QF Savings</u>

The annual net savings or net costs resulting from QF contract restructurings will be estimated each year after-the-fact. At the time of the ARP annual review, CMP will file its estimate of savings from QF contract restructuring that accrued during the prior ARP period. Other parties will have the opportunity to examine the Company's estimated savings, and present alternative estimates to the Commission.

The savings that will be shared under the ARP are the net savings during the previous calendar year from QF contract restructurings that occur on or after October 1, 1994. The net savings are defined as the reduction in CMP's production costs, less the revenue requirement of any restructuring payments made by CMP.

The revenue requirement associated with the up-front payment will be determined by amortizing the payment over the longer of the term of the restructured contract or the term of the original contract. The carrying cost component of the revenue requirement will be calculated based upon the Company's overall rate of return.

Attachment D
Treatment of Savings from Purchased Power Contract Restructurings Financed through the Finance Authority of Maine Pursuant to P.L. 1994, ch. 712.

Savings from purchased power contract restructurings financed through the Finance Authority of Maine pursuant to P.O. 1994, ch. 712 will be flowed through entirely to customers. This will be accomplished by treating the savings on a year to year basis as a flowthrough cost item, as follows:

A) The Company will file in its annual March 15 filing; 1) an estimate of annual net savings of these contract savings that will be incurred by the year ending June 30 of the following year, and 2) the actual savings passed on to customers through previous rate reductions, with an estimate of savings that would be passed through by June 30 based on current rate.

B) The net savings for the following ARP period will be the avoided purchased power contract payments, less the cost of any replacement power and less, any incremental annual payments required under the contract restructuring and the revenue requirements related to the amortization of and carrying costs on any up-front payment. Carrying costs will be calculated at the Company's overall cost of capital, including income taxes.

C) The rate change on July 1 will be the amount by which any net savings estimated through June 30 of the following year exceeds the estimated amount of savings that will be flowed through based on current rates. Conversely, if estimated net savings are less than net savings that would be flowed through based on current rates, an increase would result.

Attachment E
Illustrated Flowthrough for SFAS No. 106 Phase-in
($ in millions)

Year	SFAS No. 106 Expense	Pay-as-you-go Costs	Phase-in Amount		Total Amount in Rates	Amount Deferred	Recovery of Deferred Amounts	Total Deferred Amounts in Rates	Deferred Balance	Total Rate Request		
	(1)		(a)(4)		(1)		(b)(2)(4)			(a+b)	Specific	Index
1993	15.1	6.5	0.0		6.5	8.6	0.00	0.0	8.6	0.0	0.0	0.0
1994	13.3	5.6	0.0		5.6	7.7	0.00	0.0	16.3	0.0	0.0	0.0
1995	13.3	5.6	2.6	(3)	8.2	6.4	0.50	0.5	22.5	3.1	1.5	1.6
1996	13.3	5.6	2.6		10.8	3.8	0.60	1.1	25.5	3.2	1.6	1.6
1997	13.3	5.6	2.5		13.3	1.3	0.70	1.8	25.3	3.2	1.6	1.6
1998	13.3	5.6	0.0		13.3	0.0	0.00	1.8	23.5	0.0		
1999	13.3	5.6	0.0		13.3	0.0	0.00	1.8	21.7	0.0		
2000	13.3	5.6	0.0		13.3	0.0	0.00	1.8	19.9	0.0		
2001	13.3	5.6	0.0		13.3	0.0	0.00	1.8	18.1	0.0		
2002	13.3	5.6	0.0		13.3	0.0	0.00	1.8	16.3	0.0		
2003	13.3	5.6	0.0		13.3	0.0	0.00	1.8	14.5	0.0		
2004	13.3	5.6	0.0		13.3	0.0	0.00	1.8	12.7	0.0		
2005	13.3	5.6	0.0		13.3	0.0	0.00	1.8	10.9	0.0		
2006	13.3	5.6	0.0		13.3	0.0	0.00	1.8	9.1	0.0		
2007	13.3	5.6	0.0		13.3	0.0	0.00	1.8	7.3	0.0		
2008	13.3	5.6	0.0		13.3	0.0	0.00	1.8	5.5	0.0		
2009	13.3	5.6	0.0		13.3	0.0	0.00	1.8	3.7	0.0		
2010	13.3	5.6	0.0		13.3	0.0	0.00	1.8	1.9	0.0		
2011	13.3	5.6	0.0		13.3	0.0	0.00	1.8	0.1	0.0		
2012	13.3	5.6	0.0		13.3	0.0	(1.80)	0.0 (5)	0.0	0.0		

NOTES:

(1) Annual SFAS No. 106 expense must be reflected in rates by December 31, 1997.

(2) Any amounts deferred as a result of the phase-in must be recovered by December 31, 2012.

(3) Computation of increase-

SFAS No. 106 Expense	$13.3
Pay-as-you-go Cost	5.6
Difference	7.7
Portion Requested Above Index	0.5
Amount of Request	3.9
Phase-in Period (Years)	3
Specific Adjustment	1.3
Indexed Portion	1.3
Total	$2.6

(4) All rate changes effective July 1.

(5) Amortization stops January 31, 2012.

ASSUMPTIONS:

Actuarial studies as of December 31, 1993.

No assumed return on investment.

Actual SFAS No. 106 costs and pay-as-you-go amounts may vary form year to year.
This example does not reflect the impact those changes will have on the computation.

Attachment F
Pricing Flexibility

The Pricing Flexibility Component of the Alternative Rate Plan establishes pricing flexibility criteria for three service categories: 1) existing customer classes; 2) new customer classes for optional targeted services; and 3) special rate contracts. Pricing changes that satisfy specific criteria will be effective without Commission approval. The Plan does not preclude pricing changes that do not satisfy the criteria, but requires Commission review and approval.

For pricing changes that require Commission approval and do not involve rate increases for some customers or classes, review will take no longer than four months.[1]

I. Existing Customer Classes

The Company may set rates or rate schedules for its existing core customer classes[2] between the rate cap and a floor equal to long-term marginal cost with the following restrictions:

A. No more than two rate changes per year, in addition to any change caused annually by the rate cap adjustment.

B. If long-term marginal costs are more than 40% below prices at the rate cap, the floor will be 60% of the rate cap price.

C. The rate design established by the Commission for core customer classes will not be substantially changed by the Company without prior Commission approval. Specifically, rate elements may be changed by the Company subject to the following constraints, provided that no rate element may exceed the level of that element in the rate cap:

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[1] At various points in this document, the Plan references a review period that is described as no longer than four months. It is the understanding of the parties joining this Agreement that certain circumstances may justify a shorter than four-month review period.

[2] Defined as those rates as set forth in Exhibit 1 to Attachment F existing core customer classes may be redefined in CMP's upcoming rate design proceeding (92-315, Phase II) or in subsequent rate design proceedings during the pendency of the ARP.

1. The ratio of revenue[3] from each rate element (e.g., winter on-peak demand charge) to total class revenue will not change by more than 20%.

2. The following relationships between rate elements will maintain direction relative to 1.0 (e.g., the on-peak rate may not become equal to or less than the off-peak rate):

   a. ratio between winter rate and non-winter rate of an otherwise similar element (e.g., winter on-peak energy to non-winter on-peak energy);

   b. ratio between on-peak rate and shoulder rate of an otherwise similar element;

   c. ratio between shoulder rate and off-peak rate of an otherwise similar element.

3. The existence or lack of a block structure within a core customer rate design will be maintained. The ratio between two contiguous blocks in a particular blocked rate structure will maintain direction relative to 1.0 and will deviate from existing rate design by no more than 20%.

4. In Phase II of Docket No. 92-315, the Commission may consider and adopt changes to the constraints, identified in #1, #2 and #3 above, altering the constraints on relationships between rate elements contained in this subsection.

D. CMP's long-term marginal costs will initially be established by the Commission in Phase II of Docket No. 92-315. The Company will be required to file updated estimates of its long-term marginal costs each year at the time of the ARP annual review. These updates will be limited in scope and are intended to reflect such factors as inflation, changes in the Company's fuel price and sales forecasts, and changes in the Company's resource

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[3] Revenue calculations will be based on the same billing units used to establish the existing, Commission approved rate design.

plan.[4] During the ARP annual review, parties will have the opportunity to examine and dispute these updates, and to propose modifications to the updates proposed by the Company.

E. In the event there are significant changes to the Company's long-term marginal costs or parties wish to propose marginal cost methodological changes, parties may petition the Commission to initiate a general rate design proceeding.

F. The Company must file any proposed change to an existing rate schedule with an effective date 30 days from filing. The proposed rate schedule, along with pre-determined filing requirements,[5] will be served on a pre-determined service list. Parties will have 14 days to file written comments or objections. The Commission will suspend a proposed rate schedule only if it does not conform to the ARP requirements. In the event the Commission does suspend a rate schedule, it will make a final determination within four months of the initial filing.

G. The Company must provide regular notice to all customers that are charged rates below the rate cap. The notice should be provided upon implementation of any "discount" and once a year thereafter. The notice should include the following:

1. A statement that the customer is currently being charged rates that are below the maximum allowable retail rates, and that the Company could change these rates within the cap and floor range and, thus, may be temporary in nature;

2. Information regarding the level of the maximum allowable retail rates (i.e., rates at the capped level);

3. Information regarding the general bill impacts of rate schedules below the maximum allowable retail rates.

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[4] Major revisions to the Company's long-term marginal costs (e.g., those that involve methodological changes), if required, can be proposed in the context of a rate design proceeding.

[5] Filing requirements will be determined in an ARP compliance proceeding.

II. New Customer Classes for Optional Targeted Service

A. General

The Company may establish new or redefined customer classes with qualification criteria based on marketing characteristics identified by the Company.

1. The price cap for targeted service will be the cap that a customer in the targeted service class would face (or the most reasonable reflection of that cap) if service were taken in the applicable existing core class(es).

2. Filing and notice requirements for customers on targeted service rates will be the same as for existing core customer classes, sections I(F)(G)..

3. Unless specified in the targeted service rate schedule or a contract pursuant to the rate schedule, rates will not change more than two times per year, in addition to any change caused annually by the rate cap adjustment.

B. Temporary Usage[6]

1. The Company may establish targeted service rate schedules that will induce temporary load retention and incremental energy usage (e.g., IES, residential water heater rates).

2. Temporary service rate schedules will be designed so that, on an annual basis, or over the term of any service contract pursuant to the rate schedule, the revenue collected will be no lower than the Company's short-run marginal cost plus 1.5¢/kWh, as reasonably estimated at the time the rates were designed, for each targeted service class. Within a class, rate elements shall be reasonably designed not to be lower than the Company's short-run marginal cost, on an annual basis, projected to occur at the time the service is actually

[6] Temporary usage or temporary load is the load which is not expected to continue for an extended period and which is sensitive to changes in rates occurring after initial rate concessions. It is to be contrasted with permanent load which, once created as a result of lower rates, is expected to continue indefinitely regardless of later rate adjustments.

provided.

C. Permanent Load[7]

1. The Company may establish targeted service rate schedules that will induce load (e.g., installation of non-resistance based heating systems) that is anticipated to be served on a continuing basis.

2. Service rates for such permanent load requirements will be designed so that, on an annual basis, or over the term of any service contract pursuant to the tariff, the revenue collected will be no lower than the Company's long-term marginal cost as established pursuant to Subsection A, as reasonably estimated at the time the rates were designed, for each targeted service class. Within a class, rate elements shall be reasonably designed not to be lower than the Company's long-term marginal cost, on an annual basis, projected to occur at the time service is actually provided.

3. The Company will not promote the installation of residential baseboard resistant heating systems through targeted service rates under this provision.

4. Cost Tests[8]

In order for targeted service rates that induce permanent load to become effective in 30 days , the Company must demonstrate in its filing that the cost tests described in Section IV are reasonably likely to be satisfied:

III. Special Rate Contracts with Individual Customers .

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[7] The term "permanent load" as defined in footnote 6 on page 4 of this attachment and as used in Attachment F does not include load that is non-firm.

[8] The total resource cost test and the participants test as set forth herein represent an agreement on tests for load for the sole purpose of this proceeding and are not meant to be binding on any party for use in another proceeding or purpose, nor is any party prohibited from making any arguments either for or against such tests during the mid-period review.

A. General
The Company may enter into contractual arrangements with individual customers that govern the provision of service to that customer.

B. Short-term Contracts

1. Short-term special rate contracts are defined as those in which a discount from the rate cap is provided to a customer for five years or less in year one (1995) and year two of the ARP. Beginning in year three of the ARP, contracts shall be allowed only if the term is three years or less.

2. For contracts that retain or induce temporary load, rates charged pursuant to the contract will be designed so that, over the term of the contract, the revenue collected will be no lower than the Company's short-run marginal cost plus 1.5¢/kWh, as reasonably estimated at the time the contract was entered. Rate elements shall be reasonably designed not to be lower than the Company's short-run marginal cost, on an annual basis, projected to occur at the time service is actually provided.

3. The contract will include a provision specifying the customer's understanding that the discount provided by the contract is temporary.

4. The Company will file short-term special rate contracts to be effective 30 days from filing. Written comments or objections to the proposed special contract must be submitted within 14 days of filing. The contract will take effect unless the Commission finds that it does not conform to the ARP requirements, or is anti-competitive or unduly discriminatory.

C. Long-term Contracts

1. Long-term special rate contracts are defined as those in which a discount from the rate cap is provided to a customer for a longer period of time than that specified under the definition of short-term contracts.

2. Long-term special rate contracts require Commission review and approval. Petitions to intervene must be filed within 14 days of filing. The Commission's hearing examiner will establish the procedure, including hearing dates, for review and decision of

long-term contracts, the final decision will be issued in no longer than four months from the time of the contract's filing.

3. No party is precluded from arguing for the applicability of any criteria for approval in the four month proceeding.

D. <u>Filing Requirements and Notice</u>
The proposed special rate contract, along with pre-determined filing requirements, will be served on a pre-determined service list. Central Maine Power will, to the best of its abilities, identify and notify, upon filing, the direct competitors of the customer being offered a Special Contract. It shall provide the list of those notified in the filing. Commercial and industrial customers over 20kW or above will be informed once annually by Central Maine Power of their right to be notified in accordance with their designation of competitive SIC code(s). Any such customer will be included among those competitors notified when the SIC code(s) correspond to those of the customer being offered a Special Contract.

E. <u>Permanent Load</u>

1. For contracts that induce load that is expected to be served on a permanent basis, rates charged pursuant to the contract will be designed so that, over the term of the contract, the revenue collected will be no lower than the Company's long-term marginal cost as established pursuant to Subsection A, as reasonably estimated at the time the contract was entered. Rate elements shall be reasonably designed not to be lower than the Company's long-term marginal cost, on an annual basis, projected to occur at the time service is actually provided.

2. Central Maine Power Company, before entering special contracts for load under this provision, will take all reasonable steps to insure that any load that is anticipated to require permanent service is consistent with state energy policies and regulations and that the customer contracting with the Company is made aware of all existing CMP programs designed to insure energy efficiency.

3. Cost Tests[9]
In order to receive 30-day approval for special contract rates that induce permanent load, the Company must demonstrate in its filing that the cost tests described in Section IV are reasonably likely to be satisfied.

IV. Cost Tests for Permanent Load
In order for targeted service rates and special contract rates that induce permanent load to become effective in 30 days, the Company must demonstrate in its filing that the following cost tests are reasonably likely to be satisfied:

1. Revenue Test - The "Revenue Test" is an analysis of the direct effect of a targeted service program or special contract on the electric utility's revenues as measured by the change in the electric utility's present value of net revenue gains over the expected duration of the load. If the utility's present value of net revenue gains due to the program or contract over the expected duration of the load is greater than it would have been absent the program or contract, the program or contract passes the Revenue Test.

2. Total Resource Cost Test.[10] The "Total Resource Cost Test" is an analysis of the overall economic efficiency of the use of ratepayer resources to produce end-uses to determine whether the same end-uses can be provided more efficiently with a targeted service program or special contract than without it, considering the costs and benefits of the program to the utility, ratepayers, and participants taken together. Changes in revenue are ignored. A program or contract satisfies this test if the present value of program or contract benefits exceeds the present value of program or contract

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[9] The total resource cost test and the participants test as set forth herein, represent an agreement on tests for load for the sole purpose of this proceeding and are not meant to be binding on any party for use in another proceeding or purpose, nor is any party prohibited from making any arguments either for or against such tests during the mid-period review.

[10] The Total Resource Cost Test and the Participant Test only apply to pricing that induces permanent load in circumstances that involve a choice among alternative sources of fuel.

costs, at the time of analysis.

3. If a targeted service rate or special contract charged to residential customers or to commercial customers with load less than 20kW induces permanent load, in order to receive 30-day approval the following test must be satisfied:

<u>Participant Test</u> - <u>"The Participant Test"</u> measures the economic value of participation in a targeted service program or special contract from the participating customer's perspective. If the present value of participant benefits exceeds the present value of participant costs, the program or contract is considered to pass the Participant Test.

4. For purposes of these tests, in making the determination of the participant cost and benefit for any customer, the customer's determination of its own benefits and costs shall be deemed correct unless it is shown by factual data that the benefits or costs cannot be realized.

V. <u>Mitigation of Risks Associated with Pricing Flexibility</u>

A. <u>Revenue Delta Cap</u>
During the term of the ARP, there is a risk that lost revenue resulting from pricing flexibility will accrue to ratepayers through the operation of the earnings sharing mechanism. To mitigate against this risk, there will be an overall cap on ratepayer exposure to lost revenue from flexible pricing.

1. An overall cap on the difference between the revenue the Company would have collected if all customers were charged at the rate cap and the revenue actually collected ("Revenue Delta") will be set. This cap will be 15% of the revenue that would have been collected, on a Company-wide basis, if all customers were charged rates at the capped levels based on actual kWh used.

2. The Company will provide its estimate of the Revenue Delta at the time of the ARP annual review.

3. In the event the Revenue Delta cap is reached, or appears likely to be reached, the Company must petition the Commission for authority to continue to offer discounted rates.

B. <u>Pricing Flexibility Review</u>
A review of overall pricing flexibility will occur during the mid-period review, as provided for in Paragraph 21 of the Stipulation.

C. <u>Transition Out of ARP</u>
At the time the ARP is terminated, either in 1999 or prematurely, the Commission will consider the appropriate treatment of any discounted rates (offered through pricing flexibility) at the same time it considers any changes in rates at the cap. The Commission will explicitly consider the appropriateness of eliminating discounts to specific customer classes before increasing the cap on other rates.

D. <u>Tracking of Load Impact</u>

1. The Company will track, on an annual basis, the amount of load associated with its load growth efforts. The Company will provide a report, at the time of the ARP annual review, that details the results of its load growth efforts.

2. If the Company seeks to acquire additional generation resources, it must provide an analysis of the costs, benefits and resulting impact on rates of acquiring such additional generation resources. This analysis must include a demonstration that, ratepayers in general, taking into account all costs and benefits of pricing flexibility over the term of the ARP, are not harmed by the need to serve load induced pursuant to the terms of the ARP. This provision is not intended to restrict or reduce Commission authority to set rates in a manner that protects ratepayers from the consequences of load building.

Attachment F
Exhibit 1

List of Core Rates

Rate

A
A-LM
A-TOU
R
R-TOU
SGS
SGS-TOU
MGS-S
MGS-P
MGS-S-TOU
MGS-P-TOU
IGS-S-TOU
IGS-P-TOU
LGS-S-TOU
LGS-P-TOU
LGS-ST-TOU
LGS-T-TOU
GSS
N
AL
SL

Following are not core:

Rate

A-WH (Water Partners)
A-WH-D
A-WH-TD
SNOW
SAWMILL
IES
O

ATTACHMENT G
Customer Service and Reliability Index

The Customer Service and Reliability Index, ("CSRI"), consists of a penalty mechanism with the following terms. The CSRI is based on the following five (5) indicators:

INDICATORS	BASE LINE
I. Customer Satisfaction	
A. Percent of phone center transaction customers who respond "yes" to the question: "Was the employee you spoke with knowledgeable?" on a postcard survey administered to a random sample of customers throughout the year.	82%
B. Percent of new installation customers who respond that their installation occurred on time on a survey administered to a random sample of customers throughout the year.	72%
II. Service Reliability	
A. Customer Average Interruption Duration Index (CAIDI)	180 minutes
B. System Average Interruption Frequency Index (SAIFI)	2.0

Note: The baseline data excludes the three recent hurricanes, but includes all other weather-related outages. A method will be developed during the compliance phase of the ARP proceeding that will remove interruptions related to major storms from reported outage data. The baselines will then be revised to reflect averages for non-storm related interruptions.

III. Customer Service	
A. PUC Complaint Ratio	1.17 (1993 result)

Customer Service Penalty Mechanism

CMP's annual performance, as measured by the above indicators, will be reported to the MPUC and compared to the established baselines each year. Each indicator will be worth 20 points in a 100-point index. If the Company's performance falls below any of the five (5) established baselines, points will be deducted for each indicator which falls below the baseline. The deduction will be based on the percentage by which the indicator falls below the baseline. For example, if actual performance falls below the baseline by 2%, the deduction would be .4 points (20 x .02). If the Company achieves or exceeds the baseline in any particular indicator, it will receive the full 20 points.

The net point total will be calculated, by adding together the total points from each indicator, and a reduction in revenues of up to $3 million will be imposed for one year when the point total falls below 100, according to the following scale:

99 - 99.9	=	$250,000
98 - 98.9	=	500,000
97 - 97.9	=	750,000
96 - 96.9	=	1,000,000
94 - 95.9	=	1,500,000
92 - 93.9	=	2,000,000
Under 92	=	3,000,000

Attachment H
Least Cost Planning and
Demand-side Management Incentive Mechanism

1. Option to Review Least Cost Planning - In the event that, for two successive years, CMP fails to achieve at least 90% of the aggregate kWh and kw savings associated with demand side management ("DSM") activities as established in its most recently Commission approved Energy Resource Plan, (beginning with the plan to be filed on April 1, 1995), then any party shall have the right to petition the Commission for modification or termination of the ARP.

2. The minimum DSM Performance Threshold that must be met during 1995 will be 90% of the kWh aggregate targeted DSM savings as set forth in the annexed "1995 DSM Commitment".

3. Annual Review of DSM Performance Measurement -

   A. CMP will prepare and file a revised Energy Resource Plan by April 1, 1995;

   B. CMP will revise, amend or otherwise update, if necessary, its Energy Resource Plan annually on April 1 of each year;

   C. After review and final approval by the Commission in which all parties shall have all rights to fully participate and litigate their positions, CMP's 1995 Energy Resource Plan will serve as the basis for establishing DSM Performance Targets for 1996.

4. The DSM Performance Threshold for 1995 forward and related Performance Measurement Index shall be as follows:

   A. Performance Threshold met if 90% of targeted DSM savings in the aggregate are achieved;

   B. If less than 90% of targeted DSM savings are achieved in any given year, then a penalty in the form of a one-year reduction in revenues, which will not be considered in the calculation of earnings for purposes of profit sharing, (during the annual review of rate changes) will take place. The penalty will be calculated based on the following scale:

Savings	Revenue Reduction
85-89%	$1,500,000
80-84%	$2,000,000
75-79%	$3,000,000
less than 75%	$5,000,000 plus 25 basis point reduction in allowed rate of return on equity for purpose of calculation of profit sharing only.

C. If CMP exceeds 100% of the target for any year, a $1,000,000 credit will be established to offset any potential penalties in any subsequent year relating to this mechanism. This credit exists solely for penalty offset purposes and has no other ratemaking effect.

5. <u>"Ecowatts" Investigation</u> - Upon application by CMP respecting a specific product or program, the Commission will complete an investigation within four months of CMP's filing into the screening criteria appropriate for the marketing of new loads under an "Ecowatts" initiative, consistent with the discussions previously undertaken on this issue (see July 1994 Status Report) in the DSM Collaborative. The Company agrees not to advertise any use of electricity as environmentally beneficial prior to completion of the investigation.

1995 DSM Commitment

Goal: Attain incremental annual kWh savings of 15M kWhs (excluding Power Partners activity).

This goal will be accomplished with the following guarantees:

- The level of kWh savings will increase for all current programs or their replacements. These programs include:

  Residential:
  - Water heater wrap
  - Super Efficient Refrigerator

  Commercial/Industrial:
  - Lighting efficiency
  - Motor efficiency
  - "Custom" end-use efficiency

- An energy efficiency education component will be included in all of the following CMP activities:[1]

  ELP high use visits
  Targeted rate programs

- A commercial new construction design program will be developed during 1995 and implemented during 1996.

- Research will be performed to examine customer preferences in areas of energy efficiency.

Goal: Attain incremental annual kWh savings of 30M kWhs through Power Partners.

- Power Partners will continue to offer energy efficiency to some of our largest commercial and industrial customers in accordance with established contracts.

- Power Partners represents 65% of 1993 incremental kWh savings.

Overall 1995 aggregate incremental annual kWh savings goal is 45M kWhs.

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[1] Expenditures for these programs do not represent Chapter 380 program costs and will not be allowed specific flowthrough rate treatment.

ATTACHMENT I
ANNUAL REPORTING REQUIREMENTS

This section describes the information that CMP will provide each March 15, as support for the indexed price cap change and to provide assurance that it is complying with the provisions of the ARP. This description of information that will be provided is not intended to be complete, but should represent the types of information that will be provided by the Company. Further information may be added as part of the ARP compliance proceeding.

A. Inflation index - The Company will provide the GDP-PI, Fixed 1987 Weights, as reported by the U. S. Dept of Commerce, Bureau of Economic Analysis. The inflation rate will be calculated as the percentage change in the fourth quarter of the prior year from the fourth quarter for the preceding year.

B. Earnings Sharing Calculation - The information required to make the earnings sharing calculation will include
   i. The Company's financial statements including income statements, as provided to the Commission in its Quarterly Financial Report.
   ii. A listing of all items that would not be allowed for recovery under traditional regulation.
   iii. A calculation of the achieved return on equity, adjusted for nonrecoverable items.
   iv. A calculation of the indexed allowed rate of return, including the average Dividend Yield and Bond yield for the prior calendar year and the change from the base period for each of these two items which is 6.19% and 8.15%, respectively. These amounts are published monthly in Moody's Bond Survey.
   v. A comparison of the allowed rate of return and the earned rate of return and a calculation of the resulting price change if the difference between the two amounts is greater than 350 basis points. The calculation will be made by multiplying the average common equity for the prior year, up to the established common equity cap by the difference between the actual earned return and the relevant end of the earnings bandwidth and dividing by one minus the Company's marginal tax rate. This amount will be divided by two to determine the adjustment to the rate change.

C. Flowthrough Items - Flowthrough treatment has been provided for various items. For each item the information that will be provided to support the rate change is provided below.

i. Deferred DSM - The Company will provide the amount of expenditures for the prior calendar year, the amount of carrying costs accrued on the programs until the July 1 rate change, the annual amortization required to recover the expenditures over ten years and the carrying costs associated with the average balance related to DSM, net of application deferred taxes, calculated at the Company's average cost of capital at the end of the prior year.

ii. Reconcilable DSM - The Company will provide a schedule showing monthly revenues, expenses and under or overcollected balances related to reconcilable DSM expenditures. The increase or decrease in the price change will be the remaining balance at the end of the prior year, beginning with the 1996 rate change.

iii. FAS 106 - The Company will provide expense related to post-retirement health costs on both a pay-as-you-go basis and on an accrual basis. It will calculate the amount required under the accounting requirements to phase in the difference over the period ending 1997 and reflect one half of this amount as part of the indexed rate change.

iv. In the event that the Company is requesting mandated cost recovery for any items, it will provide a calculation and supporting schedules showing that the impact of the specific item for which recovery is sought is greater than $3 million, and that the item could not be expected to be reasonably covered in the inflation index.

D. Limited Update of Marginal Costs - The Company will file marginal costs using the methodology established in Docket No. 92-315 and reflecting yearly changes in costs and sales.

E. Customer Service and Reliability - The Company will provide the results of surveys and other measurements required to track the various customer service measurements. It will also provide a calculation showing the performance score achieved by the Company and the resultant penalty, if any, and any change in the index that may be required either as a result of a current year penalty or the expiration of a prior year penalty.

F. Pricing Flexibility - The Company will provide a schedule showing the various rates or special contracts that have been offered under the pricing flexibility provisions of the ARP, subject to applicable confidentiality provisions. It will also provide a calculation of the amount of sales and revenues under these special rates or contracts and an estimate of the total revenue that may have been achieved had no discount or special rates been provided.

G. Demand Side Management Information - The Company will provide the prior year's incremental and total annual energy reduction, and incremental and total annual winter demand reduction, from each demand side management initiative occurring during the year. The Company will continue to provide a Demand Side Management Quarterly Report, which contains additional costs, savings and activity levels for many of the initiatives.

Attachment J
Accounting Requirements

The Alternative Rate Plan is not deregulation either from a ratemaking or an accounting perspective. The Company will continue to be subject to Generally Accepted Accounting Principles (GAAP) because the rates under the Alternative Rate Plan are intended to and meet the criteria of SFAS No. 71 paragraph 5.[1] In particular, the accounting standards which specifically apply to regulated industries were considered in designing the Alternative Rate Plan. The specific standards which apply to regulated industries, when coupled with the ratemaking practices of the Commission have established a number of accounting conventions which resulted in creating "regulatory assets". In order for the Company to continue to reflect these amounts as such regulatory assets, the provisions of the applicable accounting standards, primarily Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), continue to be met.

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[1]The criteria included in paragraph 5 of SFAS No. 71 include the following:

a. The enterprise's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

b. The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products.

c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.

The SFAS No. 71 criteria generally require the Company to be able to demonstrate the probability that future revenues will be provided at least equal to the amount of the deferred cost and the regulator intends to permit recovery.[2]

To provide the Company and its auditors with the proper level of comfort required to continue present accounting practices under SFAS No. 71 and avoid significant, unintended and unacceptable write-offs of regulatory assets, the Alternative Rate Plan affirms certain accounting requirements and policies discussed below.

Continued Amortization of Regulatory Assets Currently in Rates-

In order for the Company to continue the amortization of amounts deferred in prior periods which are currently being recovered in rates, other than those specifically addressed in the Stipulation, the Alternative Rate Plan recognizes that the rates implemented as a result of the Alternative Rate Plan continue to provide specific recovery of those deferred costs in the same manner the Commission had approved in the base rate proceedings which had previously established the deferral and amortization.

In doing so, the Alternate Rate Proposal establishes the intent that the rates will permit recovery of these previously incurred costs and allow the Company to continue the amortization practices required by prior proceedings.

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[2] Paragraph 9 of SFAS No. 71 states the following:

"Rate Action of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from the inclusion of that cost in allowable costs for ratemaking purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

Fuel Accounting-

There will be no specific price changes other than those discussed (index, mandated and flow through costs, profit-sharing, etc.) for either fuel or non-fuel costs. The Company will not seek, under 35-A, M.S.R.A. §3101, recovery of deferred fuel balances that exist at the December 31, 1999 termination (whether subsequently extended or not by the Commission)of the Alternative Rate Plan. However, it is the intent of the parties that the price cap mechanism will be sufficient to recover all fuel and purchased-power costs incurred subsequent to the date of the Alternative Rate Plan.

Therefore, for accounting purposes during the period of the Alternative Rate Proposal, actual fuel costs incurred in each month will continue to be charged to expense as incurred and a corresponding amount of fuel revenues will be accrued, consistent with the current accounting practice. Fuel revenues accrued during the period covered by the Alternative Rate Plan will be computed as the amount specifically included in rates upon adoption of the Alternative Rate Plan plus an amount of the annual Alternative Rate Plan increase applicable to fuel cost recovery. The intent of this mechanism is to provide revenues for the recovery of specific fuel costs and incurred in 1995 through 1999. If fuel costs vary significantly from currently expected amounts or if annual price changes applicable to fuel during the full period of the Alternative Rate Plan are not sufficient to cover all of the fuel costs over the Alternative Rate Plan period, the Company will be required to write-off such portion of the balance in the fuel account. Over the period of the Alternative Rate Plan this accounting mechanism will create deferred fuel cost balances, however, at the end of the Alternative Rate Plan this balance is expected to be zero.

Outstanding Accounting Orders and Established Practices-

The Company has several outstanding accounting orders or established practices (F. O'Connor environmental site and the W. F. Wyman life-extension studies) which have been specifically addressed as part of the Alternative Rate Plan and, therefore, do not require additional discussion here.

Electric Lifeline Program-

The Company was required, in Docket No. 92-345, to establish a reserve account to ensure that the Company and ratepayers were protected from unusual variations between Electric Lifeline Program (ELP) amounts billed in rates and amounts expended under the ELP. Currently, the ELP reserve is in an over-collected position, however, the Company anticipates it may become under-collected during the Alternative Rate Plan period. The Company will continue the ELP reserve accounting method until the 1997 mid-period review.

Demand-side Management Costs-

As described in the Stipulation, the Company will continue to record demand-side management costs using the accounting practices currently approved by the Commission. In that regard, "hard costs" incurred after December 31, 1994, will be deferred with carrying costs and will be reflected as a mandated cost adjustment in the July 1, price change which occurs in the year following their deferral. The amount of amortization of the deferred amounts will be computed using the same methods as used in Docket No. 92-345.

With respect to "other costs", the Company will continue to reconcile the costs incurred after December 31, 1994. Currently, all costs are charged to expense in the period incurred and the difference in costs incurred and revenues collected is recorded as an over-collected or under-collected revenue. Under the Alternative Rate Plan, the Company will continue to reconcile costs but annual increases in revenues will be limited to a level of $2 million, with no increase in 1995. Any amounts above that $2 million level will continue to be reconciled, deferred and be included in mandated costs in a following period, subject to the $2 million requirement.

Postretirement Benefit Costs-

The Company has received an accounting order which allows for deferral of postretirement benefit costs (SFAS No. 106) in excess of pay-as-you-go amounts through the end of 1994. The Alternative Rate Proposal provides, in Attachment E, for a phase-in of these costs through 1997. Under this phase-in, the Company will charge to expense in the first year of the Alternative Rate Plan (1995), an amount equal to the pay-as-you-go amount plus one-third of the excess of SFAS No. 106 costs over that amount, adjusted to recover any deferred amounts over a period of 20 years. The other two-thirds of the excess will be deferred. A rate increase will be provided for 50% of the amount of expense over pay-as-you-go costs. In each of the next two years (1996 and 1997), expense will be increased by one-third of the original difference. By the end of 1997, expense will reflect an amount equal to SFAS No. 106 expense. Additionally, as outlined in Attachment E, a sufficient portion of the annual price increase in 1995, 1996 and 1997 will be applied to recover these remaining 50% of these increased costs.

This mechanism, will result in deferrals in periods subsequent to 1994. Therefore, the Company is allowed, in accordance with the Commissions Rules in Chapter 720, to continue to defer costs as demonstrated in Attachment E.

Contract Buy-out Costs

In Docket No. 92-233, the Commission required the Company to defer payments made in the restructuring of its purchased power contracts, to record carrying costs on the deferred balance at the Company's overall cost of capital and to provide deferred tax effects related to the tax benefits associated with the restructuring payments. For contract restructuring that have already occurred and that are reflected in current rates or are approved to be specifically reflected in rates, the Alternate Rate Proposal establishes the intent that those rates will permit recovery of these previously incurred costs and allow the Company to continue the amortization practices required by those prior proceedings.

When rates under the Alternative Rate Plan are put into effect, the Company will begin amortizing, on a straight-line basis, any contract buy-out costs not previously reflected in rates and consummated prior to October 1, 1994, over the remaining life of the original contract or over the term of the contract modification.

The Company will use the same accounting mechanism described above for new contract restructuring costs consummated after October 1, 1994. The revenue included in fuel costs under the Alternative Rate Plan associated with such contract restructurings shall be specifically reallocated to recover the amortization of the restructuring costs. If the Alternative Rate Plan is terminated, specific rate recognition of the remaining amortization of the restructuring costs would be granted.

New Accounting Standards-

The accounting requirements included herein, reflect the GAAP which currently exists and is applicable to the Company. If significant changes in GAAP, including changes in accounting requirements of the Securities Exchange Commission and the Federal Energy Regulatory Commission, occur in the future, the Alternative Rate Plan may have to be amended to comply with the changed requirements.

Millstone 3 Decommissioning Costs-

By Order dated June 16, 1993 in Docket No. 92-11-11, the Connecticut Department of Public Utility Control, acting pursuant to Connecticut law (the Decommissioning Financing Act of 1983), approved a three-year Decommissioning Financing Plan for Millstone Unit No. 3 (Financing Plan). Under the approved Financing Plan, the decommissioning costs effective July 1, 1994 are $421,344,020, effective January 1, 1995 are $448,731,381 and effective January 1, 1996 are $477,898,921. The Company's 2.5% share of these amounts are $10,533,601, $11,218,285, and $11,947,473, respectively. Pursuant to the June 16, 1993 Order, CMP is required to make monthly payments to the Millstone 3 decommissioning fund effective July 1, 1994 of $24,047 or $144,282 for the period through December 31, 1994. Effective January 1, 1995 the monthly payment will increase to $25,755 or $309,060 annually. Effective January 1, 1996 the monthly payment will increase to $27,445 or $329,340 annually. The Company has increased its payments beginning on July 1, 1994, pursuant to the Order. The Company is not requesting the Millstone 3 payments as a mandated cost, rather the Company will apply the appropriate portion of the annual revenues provided under the ARP to these costs.

In order for the Company to deduct its decommissioning payments on its income tax returns, the Alternative Rate Plan acknowledges the following three items:

(a) the approved Financing Plan of decommissioning costs established by the Connecticut Department of Public Utility Control is reasonable for ratemaking purposes;

(b) beginning with the first annual price cap change (effective July 1, 1995), rates will include the monthly payments of $25,755, to reflect the increase effective January 1, 1995 and beginning July 1, 1996 rates will include the monthly payment of $27,445, to reflect the increase effective January 1, 1996. The increases allowed under the cap will be applied to recover these costs; and

(c) an after tax rate of return of 6.5% for the decommissioning fund is reasonable, that rate of return being approximately equal to decommissioning escalation.